I N D I A N A   U T I L I T Y   R E G U L A T O R Y   C O M M I S S I O N

ELECTRIC REPORT TO THE REGULATORY FLEXIBILITY COMMITTEE OF THE INDIANA GENERAL ASSEMBLY

OCTOBER 2002

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Purpose and Scope of the Report

This report is intended to satisfy the requirements of Ind. Code §8-1-2.5-9(b). The report outlines the status of the Indiana electric utility industry. The report reviews the activities of the electric industry in Indiana and provides an update of facts and developments since the Indiana Utility Regulatory Commission's 2001 Energy Report.

Notable Electric Utility Proceedings

AEP Operating Agreement - Cause No. 42045

On July 24, 2001, American Electric Power Inc. ("AEP") announced that it had filed documents with the Federal Energy Regulatory Commission ("FERC") seeking approval of changes necessary to complete a planned restructuring of the corporation's regulated and unregulated holdings. AEP is the parent company of Indiana Michigan Power Company ("I&M"), an investor-owned electric utility serving approximately 565,000 customers in northern and eastern Indiana and southwestern Michigan, as well as supplying electric power at wholesale to other electric utility companies, rural electric cooperatives and municipalities.

AEP made the filings at FERC due to changes in the nature of electric regulation in some of the eleven states in which its subsidiaries operate. Restructuring laws in Ohio and Texas require corporate separation between the generating and other competitive operations and the regulated transmission and distribution operations of the AEP operating companies in those states. Other states are considering the implementation of retail competition and hence imposing similar regulations. The Public Utilities Commission of Ohio and the Public Utilities Commission of Texas have approved corporate separation plans concerning how the AEP operating companies in those states will comply with their laws. This corporate restructuring impacts not only AEP's corporate structure, but also some agreements among AEP's subsidiaries. After the restructuring, I&M and the other regulated subsidiaries will become subsidiaries of Central and South West Corporation, which will be an intermediate holding company for the regulated businesses. A second intermediate holding company will be set up for AEP's non-regulated subsidiaries. Among the agreements impacted by the proposed restructuring are the following:

- An Interconnection Agreement among the AEP Operating Companies in AEP's East zone (APCo, CSPCo, I&M, KPCo, and OPCo);
- Certain power supply agreements to which I&M is a party;
- An operating agreement with respect to Unit Nos. 1 and 2 of the Rockport Steam Electric Generating Station; and
- An Interim Allowance Agreement regarding Clean Air Act emissions allowances.

On August 1, 2001, the Indiana Utility Regulatory Commission ("IURC") initiated its own investigation (Cause No. 42045) into the proposed changes that AEP had filed with FERC. The IURC designated certain staff members as Testimonial Staff (the "IURC Staff") in this cause. Various settlements occurred as a result of negotiations between the parties in the case. A Settlement Agreement was entered into by I&M, the IURC Staff, the Office of Utility Consumer Counselor ("OUCC"), and the I&M Industrial Group ("the Settling Parties") on December 7, 2001; a Letter Agreement between I&M and the

I&M Industrial Group was filed on January 23, 2001; and a Stipulation was entered into by the Settling Parties and the Citizens Action Coalition ("CAC") on January 15, 2002.

The IURC approved the various settlements and closed its investigation on April 10, 2002. The Settlement Agreement covered these areas:

- **Capacity Requirements:** The remaining three regulated members (including I&M) of AEP-East will function the same as they did before when there were five members. I&M will file a petition with the IURC in 2007 to determine the disposition of 250 MW of capacity at Rockport Unit No. 2 that is currently under contract to an out of state utility.

- **Rate Freeze:** The current rate freeze of I&M's base and fuel rates (set to expire on January 1, 2005 and March 2004, respectively) was extended to the end of the December 2007 billing month. Only a force majeure event will enable I&M to be able to request an increase in rates.

- **Code of Conduct/Affiliate Guidelines:** The Settlement Agreement established a process to determine whether the current Codes of Conduct and Affiliate Guidelines of AEP may need revision or supplementation in light of AEP's reorganization. The IURC Staff, the OUCC, and I&M have engaged in discussions regarding new or revised affiliate guidelines, and an audit to determine compliance with affiliate standards.

- **Reliability:** AEP and I&M agreed to continue to comply with the provisions of the agreements in Commission Cause Nos. 38702-FAC40-S1 and 41210, including the Adequacy and Reliability of Retail Electric Service requirements set forth in the agreement approved in Commission Cause No. 41210 pertaining to the reliability of retail electric service as part of the Settlement Agreement. Furthermore, I&M agreed to work with the IURC Staff and the OUCC to develop guidelines for providing information to the IURC regarding unexpected service outages.

Northern Indiana Public Service Company Investigation - Cause No. 41746

On January 27, 2000, the Citizens Action Coalition and a group of ratepayers filed a complaint in Cause No. 41651 alleging that the rates and charges of Northern Indiana Public Service Company ("NIPSCO") were unreasonable and that NIPSCO had received earnings that exceeded its allowable rate of return. On May 17, 2000, the Commission issued a docket entry in that cause indicating that based upon preliminary review of NIPSCO's 1999 annual report filed on April 17, 2000, the fact that the four year periodic review was scheduled in 2000 and that NIPSCO's recent fuel adjustment cost ("FAC") filing suggest that the company may be over-earning, it intended to initiate an investigation into the reasonableness of NIPSCO's rates, docketed as Cause No. 41746.

On March 21, 2001, the Commission issued an order setting out the procedural schedule for this cause. All parties, including NIPSCO, filed their prepared testimony and exhibits constituting their respective cases-in-chief on June 8, 2001. Rebuttal testimony was filed September 7, 2001. A field hearing was held on September 26, 2001, in Gary, where members of the general public were allowed to present testimony regarding NIPSCO's rates and charges. Evidentiary hearings were held October 2 through 5, October 9 through 12, October 29 and 30 and November 5 and 6, 2001. The record was closed on January 11, 2002, with the parties' submission of proposed orders.

While the Commission Staff began the difficult process of evaluating all the oral and written testimony presented in the proceeding, the parties, including the OUCC, the CAC and the NIPSCO Industrial Group ("NIG") conducted negotiations to produce a settlement acceptable to all involved.

On May 28, 2002, the CAC filed a motion requesting an issuance of a final order in 41746. The other negotiating parties responded that they were close to a settlement and asked that the Commission delay acting on the CAC's motion.

On June 20, 2002, NIPSCO, the OUCC and the NIG submitted a Joint Settlement Agreement resolving all issues in Cause No. 41746. The CAC did not join in the settlement.

Evidentiary hearings were held on the settlement on July 22 and 23, 2002. The parties submitted proposed orders on July 30, 2002, and responses were filed August 9, 2002.

On September 23, 2002, the Commission issued an order in Cause 41746. The order accepted the settlement presented by NIPSCO, OUCC and the industrial intervenors with two modifications. First, NIPSCO would be allowed to recover only a portion of its attorney and consultant fees associated with the proceeding. Second, the Commission provided for a 60/40 sharing of current period over earnings, split NIPSCO/customers, respectively. On October 9, 2002, the Settling Parties filed notice, accepting the Commission's changes to the settlement agreement.

On October 15, 2002, the Citizens Action Coalition filed notice that it was appealing the Commission's order with the Indiana Court of Appeals.

On the same day, a motion for reconsideration of the order was filed by a group of fourteen individual intervenors. Other parties have until October 22, 2002, to file a response to the motion before the Commission will act on it.

Indiana Municipal Power Agency - Cause No. 42063

On August 15, 2001, the Indiana Municipal Power Agency ("IMPA") filed a petition[1] requesting approval of the Anderson CT Expansion Project, the SCR Project and the JTS Project. The petition also requested approval to issue bonds to finance the projects identified in the petition.

The Anderson Project involved the addition of one or more combustion turbines ("CTs") and associated facilities to IMPA's existing Anderson Station in Anderson, Indiana. Specifically, IMPA proposed to add between 80 and 120 MW of nameplate capacity by constructing one or more dual fuel (oil and natural gas) combustion turbines, together with associated equipment. The associated equipment would include one or two generator step-up transformers to increase the voltage of the power from the generator(s) to the voltage of the transmission system and a demineralization system. The demineralization system removes minerals and other chemicals from the "raw water" that will be supplied by the City of Anderson, which will help control nitrogen oxides emission ("NO_x") within permitted limits and improve the operations and life-expectancy of the combustion turbine generators.

IMPA has a 24.95% undivided ownership interest in Gibson Unit #5 and a 12.88% undivided ownership interest in Trimble County Unit #1, both of which IMPA uses as a baseload resource. The Environmental Protection Agency ("EPA") and the Indiana Department of Environmental Management ("IDEM") regulations require Gibson Unit #5 to have an operational Selective Catalytic Reduction System ("SCR") installed by May 31, 2002, to remove NO_x emissions. Similarly, the EPA and the Kentucky Department of Environmental Protection regulations require Trimble County Unit #1 to have a SCR by May 1, 2003, to remove NO_x. In its petition, IMPA requested approval to finance its share of the Gibson and Trimble County SCR projects. IMPA's total financial requirement was expected to be $40 million for its share of the two SCR projects.

IMPA, PSI Energy and Wabash Valley Power Association are all parties to an agreement that obligates each of the parties to make capital investments generally proportional to the load it serves from transmission facilities that are designated as the Joint Transmission System (JTS). IMPA recently invested in a new JTS substation, the Prescott Substation, and anticipates it will continue to fund capital improvements during the next two years to maintain its investment in the JTS proportional to its load. IMPA estimated that its total financial requirements for the JTS Project over the next two years would be $7.8 million and requested approval to finance that amount.

An evidentiary hearing was held on January 14, 2002, and a final order was issued by the Commission on February 6, 2002. The Order approved IMPA's participation in the Anderson Expansion Project, the SCR Project and the JTS Project and granted IMPA permission to issue approximately $97,800,000 in bonds to finance the projects. The

[1] The original petition was amended on September 14, 2001 to more fully describe the relief IMPA was requesting.

order also mandated certain reporting requirements that will allow the Commission to track the progress made in the projects and actual financing costs.

Indianapolis Power & Light Service Quality Investigation - Cause No. 41962

On July 8, 2001, Indianapolis Power and Light's ("IPL") service territory experienced two severe storm events, which caused significant damage to their system, as well as customer outages lasting more than 48 hours. Based, in part, on the length of the customer outages, concerns arose surrounding IPL's ability to meet their statutory duty to provide reasonable service to their customers. The Commission, therefore, initiated an investigation into the Company's service quality on July 25, 2001.

The Commission's investigation was resolved through approval of a settlement agreement[2] filed with the Commission. This agreement became effective on April 1, 2002 and will continue for three years. During that time, IPL has agreed to be held to eight performance measures at the risk of fines for non-compliance, attend quarterly service quality meetings with the Commission and other interested parties, and invest in new outage and energy management systems to improve their performance during storms. The quarterly meetings are currently ongoing and the Commission has been pleased with the level of participation by the company.

In August 2002, IPL reported it had failed three of the eight performance measures for the quarter ending June 30, 2002. This was the first quarter IPL was subject to the penalties specified in the settlement agreement. As penalty for non-performance, IPL provided $500,000 in credits to customers. An average residential or small business customer received a one-time credit of about $1.12.

Previously, IPL had provided credits of $100 to any customer who was without service for more than 36 hours following the July 2001 storm. In total, the company provided $2,037,400 in credits to customers affected by the storm outages.

PSI Energy – Cause No. 42145

On December 27, 2001, PSI Energy ("PSI") and CinCap VII filed a joint petition with the IURC requesting the following:

- The issuance of certificates of public convenience and necessity for PSI to purchase generating facilities for the furnishing of electric utility service to the public;
- Approval of the costs for such facilities; and
- Approval for CinCap VII to transfer ownership of generating assets to PSI.

[2] The settling parties included IPL, the OUCC, International Brotherhood of Electrical Workers and the IPL Industrial Group.

Specifically, PSI was requesting to purchase the 576 MW summer-rated Madison Generating Station located in Butler County, Ohio and the 129 MW summer-rated Henry County Generating Station[3] located in Henry County, Indiana. Both generating stations are currently owned by CinCap, a wholly-owned subsidiary of Cinergy and affiliate of PSI.

PSI filed its case-in-chief on March 1, 2002. Response testimony was filed by intervenors, PSI Industrial Group and Midwest Independent Power Suppliers, and the Office of Utility Consumer Counselor. The IURC Testimonial Staff filed their report on July 26, 2002. PSI filed rebuttal testimony on August 23, 2002.

A field hearing was held on August 13, 2002 in New Castle, Indiana to allow the public to provide testimony in the proceeding.

On September 18, 2002, at the scheduled evidentiary hearing, PSI submitted a Settlement Agreement between PSI, CinCap, the OUCC and the Commission Staff. At that time, non-settling intervenors, PSI Industrial Group, Midwest Independent Power Suppliers and Nucor, requested a future hearing date be set so that they could review and respond to the proposed settlement. The Commission agreed and set a hearing date of October 21, 2002.

Utilities' Environmental Compliance Proceedings

In the fall of 1998, the U.S. Environmental Protection Agency finalized a rule known as the NO_X SIP Call. The rule requires states to submit state implementation plans that address the regional transport of ground-level ozone[4]. On November 8, 2001, the EPA approved the Indiana Department of Environmental Management's NO_X rule, making the rule federally enforceable under the Clean Air Act.

The new NO_X rule requires operators of large coal fired electric generating units to reduce NO_X emissions to a *system*- wide average of 0.15 lbs. of NO_X per million BTU of heat input to *each* generating unit. The reductions must be made during each annual ozone season (May 31 through September 30, 2004 and May 1 through September 30 thereafter). Therefore, the NO_X emissions reductions required by the IDEM NO_X SIP Call are to be achieved by May 31, 2004.

[3] The Henry County Station is shown on Exhibit 1: Merchant Plants Operating in Indiana as star number 7 on page 14 of this report.

[4] NO_X, a class of compounds made of nitrogen and oxygen in varying percentages, are emitted from high temperature combustion processes including motor vehicles, fossil fuel burning electric generation facilities and other industrial and commercial sources. On hot, sunny days, NO_X reacts in the sunlight with volatile organic compounds to form ozone.

Due to the acceptance and success of the sulfur dioxide ("SO_2") Emission Allowance Trading Program[5], the EPA developed a similar market based emissions allowance trading program to be used to comply with the NO_X SIP Call. Unfortunately, due to the fact that all of Indiana's major electric generating utilities rely heavily on the burning of coal, the trading of emission allowances alone will not be enough to be in compliance with the SIP Call. To achieve the required levels of NO_X reductions mandated by the NO_X SIP Call, Indiana utilities must rely on capital-intensive retrofits to their generating facilities.

Most Indiana utilities began the implementation of low cost NO_X emission reduction strategies at their coal burning generating plants while making retrofits to comply with SO_2 emission requirements in the early to mid 1990s. These low cost strategies were quick and relatively inexpensive when compared to the capital-intensive technologies, which must now be employed to make larger reductions in NO_X emissions.

To achieve compliance at their larger, most heavily loaded generating units, Indiana utilities must make use of selective reduction technologies. Selective reduction technologies involve the injection of ammonia or urea into different zones of the combustion process. The injected agents cause a chemical process to occur that reduces NO_x to elemental nitrogen and water. In selective catalytic reduction[6] technology, a bed of catalyst (typically, titanium is used as the catalyst) is added to enhance the reactions taking place. The capital projects may be used in combination with the NO_X emission allowance market to meet the required level of NO_X emissions.

The following is a brief outline of petitions filed with the IURC by Indiana investor owned electric utilities for approval of various NO_X SIP Call compliance strategies. Included is a current best estimate of the capital cost of those compliance measures. Virtually all of the utilities have petitioned for approval of a cost recovery mechanism. Recent filings have been made to take advantage of the legislative authority granted by Senate Bill 29, effective July 1, 2002.

Senate Bill 29 encourages utilities to pursue advanced clean coal technologies that reduce regulated air emissions from electric generating plants. The bill also allows the IURC to provide incentives for certain clean coal and energy projects through the authorization of up to three (3) additional percentage points on the return on shareholder equity that a utility would otherwise be allowed to earn on such projects.

Indianapolis Power and Light

IPL filed Cause No. 42170 on July 15, 2002. IPL proposes to install SCR systems at its Petersburg Unit 2, Petersburg Unit 3, and its Harding Street Station Unit 7. By using the emission allowance market, IPL expects to avoid the installation of a fourth SCR at its

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[5] The SO_2 Emission Allowance Trading Program was developed as a method of compliance to meet stricter limitations on the emission of sulfur dioxide, as mandated by amendments made in 1992 to the Clean Air Act.

[6] Selective non-catalytic reduction ("SNCR") technologies do not employ a catalyst.

Petersburg Unit 1. IPL also plans the deployment of SNCR and other technologies at other generating units. IPL estimates approximate cost at $260 million. An evidentiary hearing was held on October 3, 2002 and the parties submitted proposed orders on October 9, 2002.

Northern Indiana Public Service Company
NIPSCO filed Cause No. 42150 on March 1, 2002. The NIPSCO proposes to install SCR systems at its Michigan City Unit 12, Bailly Units 7 and 8, and Schahfer Unit 14. NIPSCO anticipates approximate cost at $235 million.

NIPSCO and the intervening parties have reached a settlement and presented that agreement on August 13, 2002.

PSI Energy
PSI filed Cause No. 41744 on May 17, 2001. This filing was for Phase I of PSI compliance plan. Phase I consisted of NOx controls for PSI's Gallagher and Gibson stations. Specifically, that plan consisted of SCRs and Boiler Optimization at Gibson Units 1, 2, and 3; SCRs at Gibson Units 4 and 5; and SNCRs and Boiler Optimization at Gallagher Units 1, 2, 3, and 4. PSI now proposes to test new design Low NOx Burners at Gallagher rather than immediately install SNCRs at that station. An order approving Phase I was issued February 14, 2002.

PSI filed Phase II of its environmental compliance plan on August 14, 2001. Phase II, docketed as Cause No. 41744-S1, includes replacing the SNCRs with Low NOx Burners at its Gallagher Station. Other Phase II projects consist of SNCRs at Wabash River Units 2 through 6; a retrofit SCR at Cayuga Unit 1, and Boiler Optimization for virtually all of the Company's coal-fired units, including optimization systems for Gibson Units 4 and 5. An order approving Phase II was issued July 3, 2002.

PSI also considers the SCR systems added as part of the repowering project at its Noblesville Station as part of its compliance plan. PSI anticipates the cost of its environmental compliance plan to total in excess of $700 million.

Southern Indiana Gas and Electric Co. ("SIGECO")
SIGECO filed Cause No. 41864 on November 13, 2000. SIGECO was the first utility to petition for approval of its compliance plan. An order was issued on August 29, 2001. SIGECO has approval to add four SCRs at its F.B. Culley Unit 3, Warrick Unit 4 and A.B. Brown Units 1 and 2. Construction of the Culley system began in 2001 and continues. Other than pre-construction activities, construction of the other four systems has not yet begun. In Cause No. 41864 expenditure of $198 million received approval, however, SIGECO advises that these costs could be exceeded.

On June 5, 2002, SIGECO filed petition in Cause No. 42248 to take advantage of the provisions of SB 29. An order establishing the procedural schedule in this cause has not yet been issued.

Wabash Valley Power Association ("WVPA")
Wabash Valley filed Cause No. 42189 on February 26, 2002. WVPA owns a 25% share of PSI's Gibson Unit 5. Accordingly, the WVPA will pay a proportionate share of the cost of the SCR and other modifications PSI will make at Gibson 5. An order approving PSI's addition of the SCR at Gibson 5 was issued February 14, 2002 in PSI's Phase I compliance plan filing. WVPA anticipates its share of the cost to be $33 million. An order was issued in Cause No. 42189 on August 7, 2002.

Indiana Municipal Power Agency
IMPA also owns a 25% share of PSI's Gibson Unit 5. In addition, IMPA owns a share of Louisville Gas and Electric's Trimble Co. plant, in Kentucky. IMPA estimates its total financial requirement of the SCR Project for both Gibson Unit 5 and Trimble County Unit 1 is $40 million.

On August 15, 2001, IMPA filed Cause No. 42063, which requested IURC approval of its participation in the Gibson Unit 5 and Trimble County Unit 1 environmental compliance projects. As discussed in a previous section, this petition also requested approval of the construction of new generation capacity and permission to issue bonds to finance both the environmental compliance and construction projects. An order approving this petition was issued on February 6, 2002.

Hoosier Energy Rural Electric Cooperative ("Hoosier")
To achieve compliance with the NO_X SIP Call, Hoosier plans to install SCR technology on both Merom units. Installation will occur over the 2001-2003 timeframe and the SCRs are scheduled for commercial operation in July 2003. Hoosier is currently estimating cost at $73 million.

Indiana Michigan Power Co.
A compliance plan has not yet been filed by AEP, the parent company of Indiana Michigan Power.

Proceedings on Utilities' Membership in Regional Transmission Organizations – Cause Nos. 42027 and 42032

On June 25, 2001, Hoosier Energy Rural Electric Cooperative, Inc., Indianapolis Power & Light, PSI Energy, Inc., Vectren Energy Delivery of Indiana, Inc., also know as Southern Indiana Gas & Electric Company, and Wabash Valley Power Association, Inc. (collectively "Joint Petitioners") filed their petition requesting approval from the IURC of the transfer of functional control of operation of certain of their transmission facilities to the Midwest Independent Transmission System Operator ("MISO"). This petition was docketed as Cause No. 42027.

By Docket Entry dated July 26, 2001, the presiding officers determined that the proceeding filed by the Joint Petitions shared common issues of fact and law with the issues raised by a joint petition filed by Indiana Michigan Power Company d/b/a

American Electric Power and Northern Indiana Public Service Company (together, "Alliance Participants") regarding the transfer of control of transmission facilities by AEP and NIPSCO to the Alliance Regional Transmission Organization ("Alliance RTO") in Cause No. 42032. The presiding officers ordered that the two cases be consolidated. The Docket Entry also included a list of issues the Commission expected to address during the course of the proceeding.

Intervening parties to the proceeding included Citizens Action Coalition of Indiana, Inc., Indiana Municipal Power Agency, the Indiana Industrial Group ("IIG") and Enron Power Marketing, Inc. ("Enron").

An Evidentiary Hearing in the consolidated proceeding was held on November 19-21, 2001. At the hearing evidence was submitted by the Joint Petitioners and the Alliance Participants, the Indiana Office of Utility Consumer Counselor and Intervenors IIG and Enron.

In reviewing the evidence, the Commission determined that it had jurisdiction over both the petitioners in Cause Nos. 42027 and 42032 and the subject matter of the petitions, (the transfer of operational control of certain transmission facilities). The Commission then considered if the transfer of operational control of the petitioners' transmission facilities would be in the public's interest.

The Commission's deliberation focused on several public interest factors that had direct application to the Causes. These factors included how the transfer of operational control of the petitioners' transmission facilities would affect reliability, energy efficiency and rates, access to information, financial viability, and competition. When issuing the final orders, the Commission once again split the two Causes and issued a separate order for each Cause.

In Cause No. 42027, the petition of Hoosier Energy, Indianapolis Power & Light, PSI Energy, Vectren and Wabash Valley Power Association, the Commission found that Indiana electric customers should receive directly or indirectly substantial and material benefits from the utilities participating as transmission owner members in the MISO. The benefits should include reliability, enhancement of wholesale generation competition and reduction in costs. The Commission recognized, however, that the MISO was not yet operational and there would continue to be issues to be resolved before all potential benefits would be achieved. The Commission noted that the interaction between regional transmission organizations, often referred to as "seams issues," would be particularly important to resolve in order to have economic and efficient transmission transactions.
On December 17, 2001, the Commission issued an order approving the Joint Petitioners transfer of the functional control of operation of their applicable transmission facilities to the MISO.

In Cause No. 42032, the petition of NIPSCO and AEP, the Commission found that the evidence did not support the conclusion that the transfer of operational control of the utilities' transmission facilities to the Alliance RTO would provide reliable, adequate and efficient service to Indiana customers and those who serve them. The Commission particularly noted the lack of operational readiness of the Alliance RTO as a major factor in its decision. On December 17, 2001, the Commission issued its order rejecting the petitioners' request to transfer operational control of their transmission facilities to the Alliance RTO.

On January 16, 2002, AEP and NIPSCO filed an appeal with the Indiana Court of Appeals regarding the Commission's December 17, 2001 order. On July 18, 2002, AEP and NIPSCO filed a motion for voluntary dismissal of their appeal of the Commission's order in Cause No. 42027. NIPSCO and AEP indicated to the Court of Appeals that since they no longer intend to pursue efforts to obtain FERC approval of the Alliance RTO, their appeal of the Commission's order on the Alliance RTO is now moot. On July 22, 2002, the Court of Appeals granted the dismissal of the appeal.

Northern Indiana Public Service Company is currently trying to become a member of the MISO as an Independent Transmission Company ("ITC") with USA National Grid as the transmission operating company. American Electric Power is attempting to become a member of PJM also as an ITC with USA National Grid as the operating company. Please see the section beginning on page 16 for more discussion of the continuing development of regional transmission organizations.

Other Electric Industry Issues

Merchant Plants

Currently, there are six merchant power plants operating in Indiana. Four of the facilities provide electricity to the wholesale market, one provides power to Dayton Power and Light in Ohio, and one provides electricity to both PSI and the Wabash Valley Power Association. In addition, IPL has constructed two new facilities in the past few years. These plants are included in this section because the type of approval sought indicates some potential flexibility in their use by the company. Plants constructed by Whiting Clean Energy and IPL are the new additions of the summer of 2002, however, we also anticipate that the first phase of the Sugar Creek Facility will be operational shortly. A map is included, which indicates each facility's location and other pertinent details.

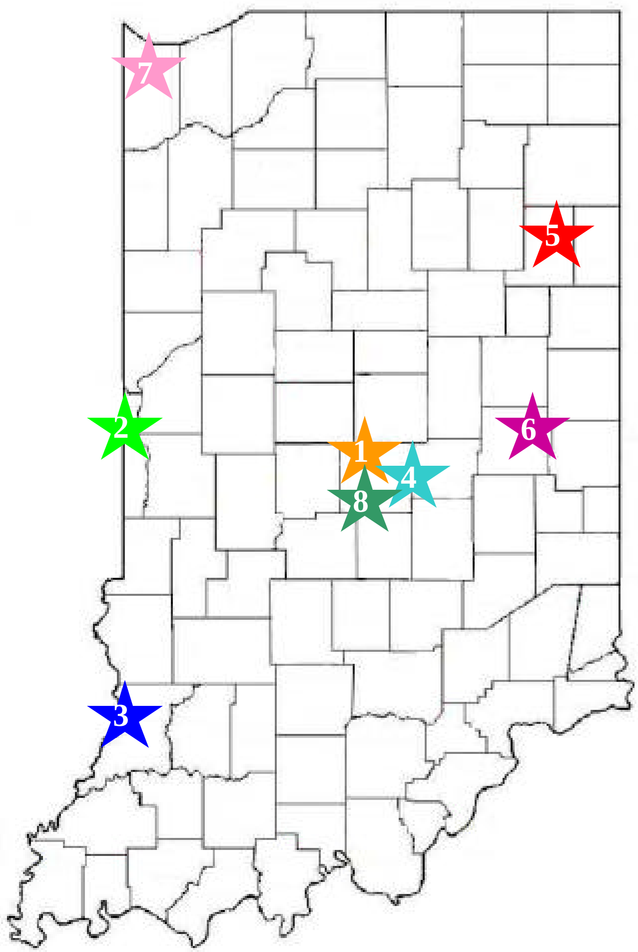
In the past year, there has been a significant nationwide decline in interest in constructing new generation for resale on the wholesale market. Many proposed plants have been delayed or discontinued. The Commission has not received a new petition for a merchant facility since March of 2001 and some of the petitions still pending have sought lengthy delays in their planning and construction schedules.

The Commission has seen an increase in the number of petitions from utilities serving Indiana retail customers. SIGECO, IPL, Hoosier Energy, IMPA, and PSI have all filed petitions in the past year or two to build new plants or to otherwise increase their capacity. The Commission has recently approved the petition of Hoosier Energy to both purchase an existing merchant plant from Williams Company and to install approximately 344 MW of new capacity in Lawrence County. IMPA was approved to increase their existing capacity at their Anderson site. PSI petitioned to repower their 1950's era coal unit in Noblesville with natural gas, thus increasing its capacity to 300 MW. SIGECO installed an 80 MW gas turbine in Posey County. IPL's capacity additions are detailed as part of the map on the following page.

Table 1: Merchant Plants Pending or Under Construction

Proposed Facility	Proposed Capacity	Location	Estimated Completion Date	Cause Number
Cogentrix	800 MW	Lawrence Co.	May 2005	41566
PSEG Lawrenceburg	1150 MW	Dearborn Co.	March 2003	41757
Sugar Creek Energy	1080 MW	Vigo Co.	Phase I in 2002	41753 & 42015
Duke Energy Knox	640 MW	Knox Co.	Undetermined	41803
Duke Energy Vigo	620 MW	Vigo Co	Undetermined	41804
Tenaska	900 MW	Pike Co.	Undetermined	41823
Putnam Energy	500 MW	Putnam Co.	Undetermined	41856
PSEG Morristown	340 MW	Shelby Co.	Undetemrined	41867
Hammond Energy	540 MW	Lake Co.	Undetermined	41900
Mt. Vernon Energy	540 or 800 MW	Posey Co.	Undetermined	41901
EnviroPower Sullivan	550 MW	Sullivan Co.	Summer 2004	41932
Acadia Bay	630 MW	St. Joseph Co.	Summer 2004	41966

Exhibit 1: Merchant Plants Operating in Indiana



1 IPL Georgetown Station (80 MW) Most output from the plant is used by IPL customers. The facility began operation in May 2000. (Cause No. 41337)

2 Duke Vermillion (640 MW) The facility's eight turbines were operational in June 2000. (Cause No. 41388)

3 Wheatland Generating Facility (500 MW) Allegheny purchased this facility from Enron in late 2000. The facility's four turbines were operational in June 2000. (Cause No. 41411)

4 DTE Georgetown Station (160 MW) This plant is located on land owned by IPL. Two turbines were operational in June 2000. (Cause No. 41566)

5 DPL Generating Station (200 MW) This plant currently has four turbines, which became operational in June 2001. (Cause No. 41685)

6 CinCap Station (135 MW) This facility became operational in August 2001. CinCap has a long-term contract with WVPA for 50 MW of the plant's output. (Cause No. 41569) There is a petition currently pending at the Commission for PSI Energy to purchase this facility for its retail peaking needs.

7 Whiting Clean Energy (525 MW) This facility began operation in April 2002 and supplies steam to the adjacent Whiting Refinery. (Cause No. 41530)

8 IPL's Harding Street Station (151 MW) This facility began operation on May 31, 2002 and is connected to the IPL system. (Cause No. 42033)

Regional Transmission Organizations ("RTOs") - Continuing Developments

The Federal Energy Regulatory Commission's Order 2000, issued in December 1999, required all public utilities that own, operate or control interstate transmission facilities to file with the FERC a proposal to join an RTO that would be operational by December 15, 2001. Order 2000 was an elaboration and clarification of earlier FERC initiatives to allow open, non-discriminatory access to transmission and encourage competitive wholesale markets. In Indiana there are two operational RTOs, Midwest ISO[7] and PJM Interconnection, L.L.C. ("PJM"). Together they interconnect wholesale customers from North Dakota to Maryland and from Manitoba to Louisiana.

Midwest ISO

The Midwest ISO is the first RTO to be approved by the FERC. The Midwest ISO is based in Carmel, Indiana, and is responsible for monitoring the electric transmission system that delivers power from generating plants to wholesale power transmitters. Most of Indiana's utilities[8] have transferred operational control of their transmission to the Midwest ISO.

The Midwest ISO began providing transmission service under its FERC tariff on February 1, 2002, thus improving the non-discriminatory open access to the transmission system and electric system reliability in the Midwest. Although operational, the Midwest ISO continues to accept new members and is working to expand and enhance the scope of its system.

On October 19, 2001, the Midwest ISO and the Southwest Power Pool[9] ("SPP") announced the consolidation of the two organizations. The organizations are now waiting on the last required regulatory approvals that are expected in the third quarter of 2002. The new consolidated organization will operate an interconnected transmission system encompassing over 120,000 megawatts of generation. SPP and the Midwest ISO have members comprised of investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, federal agencies, wholesale generators, and power marketers.

PJM

The PJM is a limited liability company formed in March 31, 1997 and was the successor of the PJM power pool. The organization is responsible for the operation and control of the bulk electric power system throughout major portions of five states, Pennsylvania, New Jersey, Maryland, Delaware, Virginia and the District of Columbia. In 1998, PJM

[7] Midwest Independent System Operator also called MISO.
[8] PSI, IPL, SIGECO, Wabash and IMPA. NIPSCO has now committed to join MISO but has not transferred functional control. For discussion of Indiana's utilities' participation in RTOs see pages 11-12.
[9] The SPP is comprised of 53 members in the southwest part of the U.S. including all or parts of Texas, Oklahoma, New Mexico, Arkansas, Kansas and Louisiana.

became the first fully functioning Independent System Operator ("ISO") and in July 2001, FERC granted PJM provisional RTO status.

The Joint and Common Wholesale Energy Market

On January 21, 2002, the Midwest ISO, PJM and SPP announced a plan to develop a single wholesale market for electricity producers and consumers in all or parts of 26 states, the District of Columbia and the Canadian province of Manitoba. The three organizations intend to move toward implementation of a single, non-discriminatory wholesale power market covering their collective regions, which would meet the needs of all customers and stakeholders. Critical design features will include maintenance and improvement of system reliability, clarity of market rules and operations, price transparency, one-stop shopping for transmission service and energy products and open network architecture that provides for growth, redundancy, security and flexibility for the future. The actual administration of the market will be undertaken by MISO and PJM.

FERC Actions

On December 20, 2001, FERC issued five interrelated orders intended to move the process forward in establishing an optimally sized RTO in the Midwest and to support the establishment of viable, for-profit independent transmission companies ("ITCs").

- In Docket RT01-87, FERC found that the Midwest ISO's RTO proposal satisfied the criteria required under Order No. 2000 for RTO status.
- In Docket ER01-3000, FERC approved the International Transmission Company's[10] request to transfer operational control of its transmission facilities to Midwest ISO and accept an agreement between International Transmission Company and Midwest ISO that would allow International Transmission Company to share certain RTO functions with Midwest ISO.
- In Docket EC01-137, FERC also approved the transfer of International Transmission Company's transmission facilities to an unaffiliated entity with no ownership interest in a market participant, facilitating a stand-alone transmission company under the Midwest ISO umbrella.
- In Docket RT01-88, FERC concluded that the Alliance Companies[11], lacked sufficient scope to exist as a stand-alone RTO and directed them to explore how their business plan, with National Grid as managing member of an ITC, could be accommodated within the Midwest ISO. FERC further concluded that the successful integration of some or all of the Alliance companies in the Midwest ISO would greatly enhance operational efficiency in the Midwest market.

The Midwest ISO and Alliance companies started negotiations and filed a compliance report on March 5, 2002, discussing how the Alliance companies could be successfully

[10] International Transmission Company is a subsidiary of DTEnergy and is engaged in the transmission of electric energy in interstate commerce and provides transmission service in Michigan. Detroit Edison is also a subsidiary of DTEnergy.

[11] The Alliance Companies included: Ameren, Dominion, American Electric Power, FirstEnergy, Commonwealth Edison, Illinois Power, Consumers Energy, Northern Indiana Public Service, Dayton Power & Light and Detroit Edison.

accommodated underneath the MISO umbrella. In this report, the Alliance companies requested further guidance from FERC in order to move the negotiations with the Midwest ISO along and indicated that they were also in negotiations with PJM, as three of their members are directly interconnected and trade actively in the PJM market.

On April 25, 2002, FERC issued an order in Docket No. EL06-65 requiring the Alliance companies to make a compliance filing within 30 days detailing which RTO they would join. The order also defined two principal functions of an RTO. First, it should design, develop, and operate the wholesale markets and it should provide super-regional oversight of security and planning and provide the means of reserving transmission capacity across the super-region. All other functions could be carried out by an ITC or the RTO.

On June 26, 2002, PJM announced that AEP, Commonwealth Edison, a subsidiary of Exelon Corporation, Illinois Power, a subsidiary of Dynegy, and National Grid had signed a memorandum of understanding with PJM to develop an ITC that would operate under PJM. The participating utilities propose to place their transmission systems under the control of the ITC, managed by National Grid, with the objective for the ITC participants to become operational within PJM during the last quarter 2002. American Electric Power, ComEd, and Illinois Power committed to joining PJM as individual transmission owners if an ITC agreement cannot be achieved.

On June 21, 2002, NIPSCO, Ameren and First Energy announced their intention to join Midwest ISO as an ITC also managed by National Grid. These three Midwest utility companies also signed a letter of intent with National Grid outlining how National Grid will manage this ITC - GridAmerica. The Midwest ISO arrangements were filed, June 20th with FERC. Pending FERC approval of a definitive agreement, National Grid will serve as the managing member of GridAmerica and will manage the transmission assets of the three utility companies and participate in the MISO on behalf of GridAmerica. The FERC has already determined National Grid is qualified as a non-market participant to be a managing member within Midwest ISO. With the approval of GridAmerica and the terms under which all three companies will join MISO, National Grid will assume responsibility for the start-up and operation of GridAmerica. The agreement between the Midwest ISO and GridAmerica provides for how GridAmerica would exercise functional control and the business structure under which it would be formed and operated. GridAmerica would be a regulated, for-profit transmission company.

On July 31, 2002, FERC conditionally approved the decision of the former Alliance companies to join the MISO and PJM under separate ITCs managed by National Grid. FERC found that the choices, standing alone, appear to produce unjust and unreasonable rates for transmission services and therefore made the approvals subject to several conditions. The conditions can be summarized as follows:

- A single market must be implemented by October 1, 2004
- National Grid performs the same functions pursuant to the same requirements in both RTOs for Day One operations

- PJM ITC Memorandums of Understanding must satisfy the delegation of functions as provided for in the April 2002 Order and the TransLink Order
- A new PJM ITC agreement must be filed within 30 days
- NERC must approve the Reliability Plans
- A new "through and out" rate must be developed
- Any ‘island’ problems raised by protestors must be addressed
- An implementation plan and frequent progress reports must be filed with FERC.

Standard Market Design (“SMD”)

Also on July 31, 2002, FERC published its notice of proposed rulemaking (“NOPR”) on Standard Market Design. FERC found that the absence of a single set of rules governing the wholesale electric industry is preventing wholesale power markets from realizing their full potential. In the NOPR, FERC proposes a series of changes to bring to fruition the kinds of markets envisioned, but not yet realized, in the Commission Orders Nos. 888 and 2000.

FERC believes the Standard Market Design is a framework in which to create genuine wholesale competition, efficient transmission systems, the right pricing signals for investment in transmission, generation facilities and demand reduction, and more customer options. Market monitoring and market power mitigation proposals are also critical parts of the proposals for standardized power market rules. FERC proposes to work closely with the states on all transmission services to retail customers to achieve non-discriminatory transmission services over the entire interstate grid. The proposal would require transmission service providers to be independent of market participants and to establish short-term electricity markets to complement bilateral contracts.

The use of Locational Marginal Pricing (“LMP”) would encourage efficient provision of transmission service and encourage the development of needed transmission, generation and demand response infrastructure. LMP reveals the value of power at each location on a grid and reduces transmission system congestion between locations. To guard against over-reliance on spot markets, FERC is proposing a resource adequacy requirement to ensure that future regional needs are addressed through self-supply or bilateral contracts. To further encourage transmission investments, FERC proposes to require industry stakeholders to participate in a regional process administered by an independent transmission provider to identify the most efficient and effective means to maintain reliability and eliminate critical transmission constraints. Efficient market design can eliminate opportunities for market manipulation, however market monitoring at all times, and market power mitigation when needed, are still critical aspects of this initiative.

Mergers and Acquisitions

Mergers are viewed with caution by federal and state regulatory agencies because the merged entity may be able to exercise increased market power resulting in noncompetitive prices, lack of product innovation and a decrease in the range and quality of service to the consumer. Mergers can also threaten state commerce by reducing job levels or draining employees from one state to another. Some mergers, however, result in substantial benefits to the shareholders, customers and employees of the merged companies. All proposed mergers or acquisitions should be objectively analyzed to identify the potential negative and positive outcomes. Traditional merger evaluation criteria are based on the need to review mergers of companies operating in a competitive industry. The energy industry, however, has a natural tendency for developing a monopoly market making it particularly critical that mergers among energy utilities undergo a thorough evaluation before final approval. It is difficult to apply traditional merger evaluation criteria when analyzing mergers among energy utility companies because some utility functions remain regulated monopolies while others are in the initial stages of transition to more competitive markets.

Prior to 1996, electric utility merger applications argued that customers would realize substantial savings due to the coordination of generating unit dispatch and other operations. In April 1996, the Federal Energy Regulatory Commission issued Order 888, which requires transmission-owning utilities to allow other power suppliers equal access to their transmission systems on non-discriminatory terms. As a result, many of the previously touted coordination benefits can now be achieved without a merger.

Today, mergers of both electric and gas utilities frequently produce comparatively small savings from reduced administrative costs and other economies of size (scale). Often merger savings are offset by the inefficiencies associated with the operation of a much larger organization. As a result, the customer may experience little or no reduction in the cost of electricity or natural gas and decreased customer choice and service.

Mergers or acquisitions of Indiana electric utilities can have several effects. First, the parent company may opt to reduce the workforce of the Indiana utility, which can result in reduced service quality and reliability. Second, if the parent company owns subsidiaries that operate in other states, the Indiana company's customers can be affected by policies put into place in the other states. For example, if other states enact customer choice programs, the parent company may need to create new interconnection and operating agreements for its subsidiaries. The need for new agreements also shows/exhibits/points to the need for additional safeguards for state regulatory agencies in the areas of access to books and records, codes of conduct and affiliate rules. The split among states of choice and regulation may also have the inadvertent detrimental affect of reducing the economies of scale and scope of the large multi-state operation in the areas of generation dispatching, and planning for transmission, new generation, and environmental equipment.

Indiana's Electric Industry - Statistics

This section is a review of the energy sales, revenue, average price and market share for Indiana's electric utilities.

Investor-Owned Utilities
There are five investor-owned utilities operating in Indiana. These utilities are the most significant in terms of generation and in number of customers served. The five investor-owned utilities that operate within the state are:

- Indianapolis Power & Light, a wholly-owned subsidiary of AES Corporation;
- Indiana Michigan Power, wholly owned by American Electric Power;
- Northern Indiana Public Service (NIPSCO), a NiSource company;
- PSI Energy, a wholly-owned subsidiary of Cinergy Corporation; and,
- Southern Indiana Gas & Electric Company, a subsidiary of Vectren Energy Delivery of Indiana.

Municipal Utilities
There are 79 municipally owned electric utilities in Indiana. As of July 2001, twenty-three remain under IURC jurisdiction for rate regulation. Many municipals in the state are members of the Indiana Municipal Power Agency. IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power.

IMPA owns generating facilities and has member-dedicated generation. It also holds ownership interest in two units, Gibson 5 (co-owned with PSI and Wabash Valley Power Association) and Trimble County 1 (co-owned with Louisville Gas and Electric and the Illinois Municipal Electric Agency). It meets the rest of its members' needs through purchased power.

Cooperatives
There are forty-three electric distribution co-ops operating in Indiana. As of July 2001, four co-ops remain under Commission jurisdiction for rate regulation. Most of the distribution co-ops are members of either Hoosier Energy or Wabash Valley Power Association. These two organizations are generating and transmission cooperatives formed to supply power to distribution co-ops. Hoosier Energy and WVPA serve as coordinators of bulk power supplies and transmission services for their members.

Sales, Revenues And Market Share For Electric Utilities

2001 Summary

MWH

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	22,363,817	18,448,400	37,855,391	370,920	79,038,528
Rural Electric Membership Corporations	976,624	451,925		4,062	1,432,610
Municipal Utilities	1,353,854	3,285,482		83,392	4,722,728
Totals	**24,694,295**	**22,185,807**	**37,855,391**	**458,373**	**85,193,866**

REVENUE (000s)

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	$1,534,766	$1,107,606	$1,539,633	$42,133	$4,224,138
Rural Electric Membership Corporations	$68,372	$25,046		$319	$93,736
Municipal Utilities	$83,087	$159,144		$7,191	$249,422
Totals	**$1,686,225**	**$1,291,796**	**$1,539,633**	**$49,643**	**$4,567,296**

RETAIL MARKET SHARE BY MWH

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	90.56%	83.15%	100.00%	80.92%	92.77%
Rural Electric Membership Corporations	3.95%	2.04%		0.89%	1.68%
Municipal Utilities	5.48%	14.81%		18.19%	5.54%

RETAIL MARKET SHARE BY REVENUES

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	91.02%	85.74%	100.00%	84.87%	92.49%
Rural Electric Membership Corporations	4.05%	1.94%		0.064%	2.05%
Municipal Utilities	4.93%	12.32%		14.49%	5.46%

Please note that REMCs and municipal utilities do not present separate commercial and industrial information in the annual reports they submit to the Commission therefore the summarized commercial and industrial data is shown under the “Commercial” heading on the tables.

GENERATION CAPACITY BY UTILITY (MW)

Utility	Nameplate	Summer	Winter
Indiana Michigan Power Company	3,708	3,583	3,599
Indianapolis Power & Light Company	3,510	3,134	3,250
Northern Indiana Public Service Company	4,098	3,392	3,392
PSI Energy, Inc.	6,804	6,176	6,260
Southern Indiana Gas & Electric Company	1,517	1,391	1,422
Hoosier Energy	1,313	1,244	1,266
Wabash Valley Power Association	156	156	156
Indiana Municipal Power Agency	155	144	164

Investor-Owned Electric Utilities
2001 Data

MWH

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	5,413,402	4,772,584	7,914,371	84,610	18,184,967
Indianapolis Power & Light Company	4,717,218	1,955,002	7,337,280	71,637	14,081,137
Northern Indiana Public Service Company	2,956,872	3,446,339	8,935,539	127,528	15,466,278
PSI Energy, Inc.	7,865,063	6,891,120	11,241,445	67,979	26,065,607
Southern Indiana Gas & Electric Company	1,411,262	1,383,355	2,426,756	19,166	5,240,539
Totals	**22,363,817**	**18,448,400**	**37,855,391**	**370,920**	**79,038,528**

REVENUE (000s)

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	$350,600	272,270	$323,157	$6,531	$952,559
Indianapolis Power & Light Company	298,779	127,863	334,387	10,415	762,444
Northern Indiana Public Service Company	295,641	292,931	404,000	14,098	1,006,669
PSI Energy, Inc.	502,243	339,707	396,271	8,967	1,247,189
Southern Indiana Gas & Electric Company	96,503	74,834	81,817	2,123	255,277
Totals	**$1,534,766**	**$1,107,606**	**$1,539,633**	**$42,133**	**$4,224,138**

AVERAGE RATE PER KWH

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	$0.06	$0.06	$0.04	$0.08	$0.05
Indianapolis Power & Light Company	$0.06	$0.07	$0.05	$0.15	$0.05
Northern Indiana Public Service Company	$0.10	$0.08	$0.05	$0.11	$0.07
PSI Energy, Inc.	$0.06	$0.05	$0.04	$0.13	$0.05
Southern Indiana Gas & Electric Company	$0.07	$0.05	$0.03	$0.11	$0.05

RETAIL MARKET SHARE

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	36.81%	28.58%	33.93%	0.69%	100%
Indianapolis Power & Light Company	38.01%	16.77%	43.86%	1.37%	100%
Northern Indiana Public Service Company	29.37%	29.10%	40.13%	0.00%	100%
PSI Energy, Inc.	40.27%	27.24%	31.77%	0.72%	100%
Southern Indiana Gas & Electric Company	37.80%	29.31%	32.05%	0.83%	100%

Rural Electric Membership Corporations

2001 Data

MWH

Utility	Residential	Commercial & Industrial	Other	Total
Harrison County R.E.M.C.	304,084	173,390	2,211	479,685
Jackson County R.E.M.C.	340,780	73,417		414,197
Marshall County R.E.M.C.	65,502	14,974	960	81,435
Northeastern R.E.M.C.	266,258	190,143	891	457,293
Totals	**976,624**	**451,925**	**4,062**	**1,432,610**

REVENUE (000s)

Utility	Residential	Commercial & Industrial	Other	Total
Harrison County R.E.M.C.	$19,822	$8,520	$169	$28,511
Jackson County R.E.M.C.	24,009	4,034		28,043
Marshall County R.E.M.C.	5,898	1,199	96	7,193
Northeastern R.E.M.C.	18,642	11,293	54	29,989
Totals	**$68,372**	**$25,046**	**$319**	**$93,736**

AVERAGE REVENUE PER KWH

Utility	Residential	Commercial & Industrial	Other	Total
Harrison County R.E.M.C.	$0.07	$0.05	$0.08	$0.06
Jackson County R.E.M.C.	$0.07	$0.05		$0.07
Marshall County R.E.M.C.	$0.09	$0.08	$0.10	$0.09
Northeastern R.E.M.C.	$0.07	$0.06	$0.06	$0.07

RETAIL MARKET SHARE

Utility	Residential	Commercial & Industrial	Other
Harrison County R.E.M.C.	69.52%	29.88%	0.59%
Jackson County R.E.M.C.	85.62%	14.38%	0%
Marshall County R.E.M.C.	82.00%	16.66%	1.34%
Northeastern R.E.M.C.	62.16%	37.66%	0.18%

Municipal Electric Utilities

2001 Data

MWH

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	314,349	394,420	4,650	713,419
Auburn Municipal Electric	55,874	437,789		493,663
Bargersville Municipal Power & Light	29,328	4,893	14,013	48,234
Boonville Municipal Light & Power	N/A	N/A	N/A	
Columbia City Municipal Electric	34,073	72,893	2,643	109,610
Crawfordsville Municipal Electric Light & Power	75,226	310,099	2,833	388,157
Edinburgh Municipal Electric	21,999	65,598	1.141	88,738
Frankfort City Light & Power	73,154	256,416	2,598	332,168
Garrett Municipal Electric	57,756			57,756
Kingsford Heights Municipal Electric	5,128			5,128
Knightstown Municipal Electric	12,730	8,848	410	21,988
Lawrenceburg Municipal Electric	26,927	83,863	2,873	113,663
Lebanon Municipal Electric	60,212	126,779	2,987	189,977
Logansport Municipal Electric	98,091	280,895	2,662	381,649
Mishawaka Municipal Electric	175,704	368,120	25,955	569,778
Paoli Municipal Electric	N/A	N/A	N/A	
Peru Municipal Electric Light & Power	N/A	N/A	N/A	
Richmond Municipal Power & Light	198,820	716,543	11,057	926,420
South Whitley Municipal Electric	N/A	N/A	N/A	
Straughn Municipal Electric	1,437			1,437
Tipton Municipal Electric	37,008	74,051	215	111,274
Troy Municipal Electric	10,170			10,170
Washington City Municipal Light & Power	65,869	84,275	9,355	159,499
Totals	**1,353,584**	**3,285,482**	**83,392**	**$4,722,728**

REVENUE (000s)

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	$19,647	$20,211	$398	$40,256
Auburn Municipal Electric	2,551	19,939	281	22,771
Bargersville Municipal Power & Light	1,960	342	983	3,285
Boonville Municipal Light & Power	N/A	N/A	N/A	
Columbia City Municipal Electric	2,173	4,218	277	6,669
Crawfordsville Municipal Electric Light & Power	5,152	15,477	235	20,864
Edinburgh Municipal Electric	1,265	3,442	88	4,795
Frankfort City Light & Power	4,326	10,558	217	15,101
Garrett Municipal Electric	3,800		83	3,883
Kingsford Heights Municipal Electric	376			376
Knightstown Municipal Electric	720	515	40	1,275
Lawrenceburg Municipal Electric	1,480	4,313	228	6,021
Lebanon Municipal Electric	3,735	6,071	264	10,069
Logansport Municipal Electric	6,250	13,997	129	20,376
Mishawaka Municipal Electric	11,690	20,781	2,360	34,831
Paoli Municipal Electric	N/A	N/A	N/A	
Peru Municipal Electric Light & Power	N/A	N/A	N/A	
Richmond Municipal Power & Light	11,709	31,131	940	43,781
South Whitley Municipal Electric	N/A	N/A	N/A	
Straughn Municipal Electric	96			96
Tipton Municipal Electric	2,077	3,676	21	5,774
Troy Municipal Electric	233	377	25	634
Washington City Municipal Light & Power	3,848	4,097	621	8,567
Totals	**$83,087**	**$159,144**	**$7,191**	**$249,422**

AVERAGE PER KWH

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	$0.06	$0.05	$0.09	$0.06
Auburn Municipal Electric	$0.05	$0.05		$0.05
Bargersville Municipal Power & Light	0.07	0.07	0.07	0.07
Boonville Municipal Light & Power	$ N/A	$ N/A	N/A	$ N/A
Columbia City Municipal Electric	$0.06	$0.06	0.10	$0.06
Crawfordsville Municipal Electric Light & Power	$0.07	$0.05	0.08	$0.05
Edinburgh Municipal Electric	$0.06	$0.05	0.08	$0.05
Frankfort City Light & Power	$0.06	$0.04	$0.08	$0.05
Garrett Municipal Electric	$0.07			$0.07
Kingsford Heights Municipal Electric	$0.07			$0.07
Knightstown Municipal Electric	$0.06	$0.06	$0.10	$0.06
Lawrenceburg Municipal Electric	$0.05	$0.05	$0.08	$0.05
Lebanon Municipal Electric	$0.06	$0.05	$0.09	$0.05
Logansport Municipal Electric	$0.06	$0.05	$0.05	$0.05
Mishawaka Municipal Electric	$0.07	$0.06	0.09	$0.06
Paoli Municipal Electric	N/A	N/A	N/A	N/A
Peru Municipal Electric Light & Power	N/A	N/A	N/A	N/A
Richmond Municipal Power & Light	$0.06	$0.04	0.09	$0.05
South Whitley Municipal Electric	N/A	N/A	N/A	N/A
Straughn Municipal Electric	$0.07			$0.07
Tipton Municipal Electric	$0.06	$0.05	$0.10	$0.05
Troy Municipal Electric	$0.02			0.06
Washington City Municipal Light & Power	$0.06	$0.05	$0.07	$0.05

RETAIL MARKET SHARE

Utility	Residential	Commercial & Industrial	Other
Anderson Municipal Light & Power	48.81%	50.21%	0.99%
Auburn Municipal Electric	11.20%	87.56%	1.24%
Bargersville Municipal Power & Light59.67	59.67%	10.41%	29.93
Boonville Municipal Light & Power	N/A	N/A	N/A
Centerville Municipal Power & Light	32.59%	63.25%	4.16%
Crawfordsville Municipal Electric Light & Power	24.69%	74.18%	1.13%
Edinburgh Municipal Electric	26.38%	71.78%	1.84%
Frankfort City Light & Power	28.65%	69.92%	1.43%
Garrett Municipal Electric	97.85%	0	2.15%
Kingsford Heights Municipal Electric	100.00%	0%	0%
Knightstown Municipal Electric	56.48%	40.42%	3.10%
Lawrenceburg Municipal Electric	24.58%	71.63%	3.79%
Lebanon Municipal Electric	37.09%	60.29%	2.62%
Logansport Municipal Electric	30.67%	68.69%	0.63%
Mishawaka Municipal Electric	33.56%	56.66%	6.78%
Paoli Municipal Electric	N/A	N/A	N/A
Peru Municipal Electric Light & Power	N/A	N/A	N/A
Richmond Municipal Power & Light	26.74%	71.11%	2.15%
South Whitley Municipal Electric	N/A	N/A	N/A
Straughn Municipal Electric	100.00%	%	%
Tipton Municipal Electric	35.98%	63.66%	0.36%
Troy Municipal Electric	36.71%	59.42%	3.87%
Washington City Municipal Light & Power	44.92%	47.83%	7.25%

Average Revenue per kWh by State (ranked from highest to lowest)

STATE	1999	1999	2000	2000	2001 (EST)	2001 (EST)
	Residential	Average	Residential	Average	Residential	Average
Hawaii	14.30	11.97	16.37	14.04	16.90	14.60
New Hampshire	13.84	11.75	13.58	11.60	13.30	11.55
Rhode Island	10.13	9.02	11.56	10.19	12.30	11.05
Vermont	12.17	10.28	12.00	10.14	12.45	11.00
New York	13.32	10.40	14.06	11.15	13.75	10.65
Massachusetts	10.09	9.16	10.84	9.48	11.95	10.65
California	10.71	9.34	10.58	8.50	11.30	10.55
Alaska	11.16	9.78	11.44	9.98	11.45	10.10
Connecticut	11.46	9.96	10.87	9.53	10.45	9.45
New Jersey	11.40	9.99	10.75	9.03	9.55	8.80
Louisiana	7.12	5.81	7.78	6.55	8.95	8.00
Maine	13.07	9.77	12.81	9.88	6.10	7.75
Florida	7.73	6.85	7.77	6.91	8.45	7.60
New Mexico	8.62	6.58	8.33	6.58	8.30	7.35
Michigan	8.73	7.14	8.50	7.11	8.20	7.10
Texas	7.55	6.04	7.78	6.40	7.85	6.90
Pennsylvania	9.19	7.67	9.10	6.57	8.35	6.80
District of Columbia	8.00	7.45	7.88	7.44	7.15	6.55
North Carolina	7.99	6.44	8.03	6.49	7.65	6.50
Arizona	8.53	7.23	8.29	7.09	7.05	6.40
Montana	6.78	5.01	6.33	5.09	6.60	6.40
Nevada	7.13	5.93	7.37	6.10	7.75	6.35
Ohio	8.68	6.40	8.61	6.51	7.55	6.30
Delaware	9.17	7.12	9.16	6.81	7.70	6.15
South Dakota	7.42	6.35	7.39	6.31	6.90	6.15
Mississippi	6.75	5.65	7.02	5.91	6.75	6.15
Wisconsin	7.31	5.53	7.56	5.69	7.80	6.05
Illinois	8.83	6.98	8.84	6.57	7.80	6.00
Oklahoma	6.60	5.37	7.00	5.83	6.70	6.00
Maryland	8.39	7.04	8.00	6.73	6.70	5.90
Virginia	7.48	5.86	7.61	5.95	6.90	5.90
Georgia	7.56	6.24	7.61	6.17	6.75	5.85
Colorado	7.38	5.95	7.37	5.98	7.10	5.85
Kansas	7.64	6.22	7.55	6.21	6.80	5.75
Arkansas	7.43	5.68	7.45	5.73	6.95	5.65
Tennessee	6.34	5.63	6.36	5.61	6.25	5.65
Minnesota	7.41	5.83	7.39	5.79	7.10	5.60
South Carolina	7.55	5.57	7.43	5.46	6.90	5.40
North Dakota	6.50	5.49	6.64	5.52	5.80	5.35
Iowa	8.35	5.93	8.08	5.82	6.40	5.30

STATE	1999	1999	2000	2000	2001 (EST)	2001 (EST)
	Residential	Average	Residential	Average	Residential	Average
Alabama	7.03	5.54	6.99	5.57	6.35	5.25
Washington	5.10	4.10	5.14	4.48	5.40	5.25
Utah	6.27	4.86	6.27	4.81	6.80	5.10
Missouri	7.12	6.07	6.96	5.95	5.50	5.00
West Virginia	6.27	5.09	6.36	5.11	5.95	5.00
Oregon	5.75	4.87	5.96	4.78	5.85	5.00
Indiana	6.96	5.29	6.87	5.14	6.15	4.95
Nebraska	6.52	5.31	6.40	5.21	5.30	4.70
Idaho	5.26	3.98	5.43	4.18	5.35	4.50
Wyoming	6.34	4.30	6.65	4.38	6.20	4.35
Kentucky	5.58	4.17	5.36	4.13	5.00	4.00
U.S. Average		6.66		6.67		6.82

Sources: Energy Information Administration: EIA-861, "Annual Electric Utility Report," and EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions."

Glossary

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-user. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

Independent System Operator (ISO): An independent organization or institution that controls the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Kilowatt (kW): A basic unit of measurement; 1 kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Megawatt (MW): One thousand kilowatts or one million watts.

Megawatt-Hour (MWh): One megawatt of power supplied to or taken from an electric circuit steadily for one hour.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

List of Acronyms

AEP	American Electric Power
APCO	Appalachian Power Company, subsidiary of AEP
BTU	British Thermal Unit
CAC	Citizens Action Coalition
CSPCO	Columbus and Southern Power Company, subsidiary of AEP
CT	Combustion Turbine
EPA	Environmental Protection Agency
FAC	Fuel Adjustment Cost Charge
FERC	Federal Energy Regulatory Commission
ITC	Independent Transmission Company
IDEM	Indiana Department of Environmental Management
IIG	Indiana Industrial Group
I&M	Indiana Michigan Power Company, subsidiary of AEP
IMPA	Indiana Municipal Power Agency
IOU	Investor-owned Utility
IPL	Indianapolis Power and Light
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission
JTS	Joint Transmission System
KPCO	Kentucky Power Company, subsidiary of AEP
LMP	Locational Marginal Pricing
MW	Megawatt
MWH	Megawatt Hour
MISO	Midwest Independent System Operator
NO_x	Nitrogen Oxides
NIPSCO	Northern Indiana Public Service Company
NOPR	Notice of Proposed Rulemaking
OUCC	Office of Utility Consumer Counselor
OPCO	Ohio Power Company
PSI	PSI Energy
REMC	Rural Electric Membership Cooperative
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SIGECO	Southern Indiana Gas & Electric Company

SMD	Standard Market Design
SO_2	Sulfur Dioxide
WVPA	Wabash Valley Power Association